Application No.: R.12-03-014
Exhibit No.: ISO-2
Witness: Robert Sparks

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

TRACK 4 REBUTTAL TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA**

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

**TRACK 4 REBUTTAL TESTIMONY OF ROBERT SPARKS
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION**

Q. What is your name and by whom are you employed?

A. My name is Robert Sparks. I am employed by the California Independent System Operator Corporation (ISO), 250 Outcropping Way, Folsom, California as Manager, Regional Transmission.

Q. Have you previously submitted testimony in Track 4?

A. Yes. On August 5, 2013, I submitted opening testimony on behalf of the ISO containing the results of the ISO's Track 4 studies and an explanation of the modeling and study methodology.

Q. What is the purpose of your rebuttal testimony?

A. Numerous parties to this proceeding have taken issue with the ISO's study methodology and identification of residual resource needs in the absence of SONGS. In this rebuttal testimony, I will respond to issues involving the technical aspects of the ISO's studies and application of the NERC/WECC reliability standards. Mr. Millar will address topics raised by parties regarding the ISO's transmission planning studies and the joint agency reliability report on the SONGS retirement, as well as some recommendations for the Commission's consideration.

The ISO's Study Methodology: Transmission Planning Standards, the N-1-1 Contingency and Load-Shedding

Q. Many of the parties to this Track 4 proceeding, including SCE and SDG&E, have raised issues about the ISO's application of NERC/ WECC/ISO transmission planning standards embodied in the study methodology approved by the Commission in D.13-02-015 (Track 1 decision) and also in D.13-03-029 (SDG&E procurement decision). Do you believe that this topic and the ISO's study methodology in general are issues to be addressed in Track 4?

A. No. As I discussed in my opening testimony, according to the May 21, 2013, Revised Scoping Ruling, the ISO was to determine the residual local capacity needs in the LA Basin and San Diego local areas (combined into a SONGS study area), using the assumptions approved in D.13-02-015 and D.13-03-029, assuming a SONGS outage for years 2018 and 2022 and SONGS online in 2022. The ISO's local capacity requirement (LCR) study methodology was thoroughly litigated in both proceedings and it was approved in both decisions. This study methodology includes the ISO's position that load shedding in the highly urbanized San Diego local capacity area is not appropriate to mitigate the N-1-1 contingency of overlapping outages of the SWPL and Sunrise Powerlink transmission lines. Indeed, as I explained in rebuttal testimony recently submitted in the Commission proceeding evaluating the need for the Pio Pico generation facility, Docket A.13-06-015, the ISO takes the same position with respect to load shedding as a transmission planning mechanism in highly urbanized areas of the ISO grid in all areas of the grid, including the SCE and PG&E service territories (see Exhibit No. ISO-3).

Q. Based on the testimony presented in Track 4, should the Commission re-evaluate its prior decisions regarding the ISO's study methodology and the ISO's position on load shedding for N-1-1 contingencies?

A. No. None of the parties submitting testimony have presented any compelling basis for the Commission to change its determinations in D.13-02-015 and D.13-03-029 that the ISO's LCR methodology should be used to determine local capacity needs for the LA Basin and the San Diego local areas. In fact, as described below, much of the intervener's testimony is factually incorrect.

Q. Both SDG&E and SCE ran studies that included load shedding in the San Diego local area for the overlapping outage of SWPL and Sunrise. Does the ISO believe that these parties recommend load shedding as a long term mitigation solution for this N-1-1 contingency?

A. No, I don't believe that either party recommends load shedding in highly urbanized areas for Category C contingencies, consistent with the ISO's position on this issue. Although both SDG&E and SCE presented a scenario with load shedding, both parties also based their procurement recommendations and requests for additional procurement on the results of the ISO's studies that did not include load drop (See SCE-1, page 44 and page 2 of Mr. Jontry's testimony). At page 37 SCE also makes the point that the Mesa loop-in does not effectively address the N-1-1 contingency, and that load shedding or additional generation in San Diego is more effective at addressing the N-1-1 contingency.

Q. Based on your understanding that SCE is not recommending load shedding for the N-1-1 contingency in SDG&E, does the ISO have any concerns with SCE's other study assumptions?

A. Yes. At SCE-1, page 27, SCE notes that their studies meet NERC reliability standards but not the "more stringent" requirements used by the ISO. One of the standards referred to is the WECC requirement that, in order to account for modeling uncertainties (e.g. power factor, equipment mis-operation during contingencies, variations in neighboring system models, etc) without resulting in voltage collapse and wide area blackouts, the modeled amount of load should be increased by 5% for Category A or B and 2.5% for Category C contingencies. SCE refers to this adjustment as an ISO requirement but notes, at footnote 21, that this is a WECC Regional Business Practice.

This WECC Regional Business Practice was approved in 2011 by the WECC Planning Coordination Committee, which includes SCE as a member, and the WECC Board of Directors. While SCE states that their studies, which do not account for this WECC reactive margin, reduce the risk of monetary sanctions to the ISO, SDG&E and SCE, the ISO does not share this view. Indeed, in the event of a blackout related to inadequate reactive margin, the ISO believes that NERC may view this as a violation, and it is possible that it could seek to impose monetary penalties for non-compliance with this widespread and well-accepted business practice. At a minimum, this regional business practice is an industry best practice which the ISO believes should be followed. It is also worth noting that the WECC planning standard for reactive power was utilized in the 2012 SCE Annual Transmission Reliability Assessment report published by SCE.

Q. Have other witnesses in Track 4 also recommended that additional local capacity needs for the LA Basin/San Diego study area be based on an assumption that SDG&E will drop load as a permanent mitigation solution for the N-1-1 contingency?

A. Yes. This topic was addressed in detail by witnesses Powers (Sierra Club), May (CEJA), Fagan (DRA), Woodruff (TURN), Caldwell (CEERT), Peffer (POC) and Firooz (City of Redondo Beach); they raise mostly the same issues that I address above. I will respond to some of their arguments in this rebuttal testimony and Mr. Millar will respond to other topics.

Q. Isn't load shedding permitted by NERC reliability standard TPL 003 in response to a Category C N-1-1 event?

A. Yes, and the ISO has load shedding in small amounts through special protection schemes (SPS) on the sub-transmission system or for extreme category D contingencies. However, although NERC TPL 003 *permits* load shedding as a mitigation for an N-1-1 contingency, the standard does not *require* the ISO, as the Planning Coordinator, to approve an automatic load shedding SPS under all such circumstances and instead requires the Planning Coordinator to consider system design and expected system impacts in deciding whether an automatic load shedding SPS is appropriate. The historical practice has been, as a last resort, to rely on large amounts of urban load shedding as an interim measure only. In fact, there are two such load shedding arrangements currently in place, both of which have transmission projects underway to eliminate the need for the load shedding. The ISO notes as well, that load shedding was also relied upon in SCE's south Orange County area to mitigate one N-2 outage until the Del Amo-Ellis loop in project could be completed in the summer of 2012, and a different load shedding arrangement was relied upon until the Barre-Ellis reconfiguration and the Johanna, Santiago and Viejo shunt capacitor bank projects could be completed in the summer of 2013.

Q. Why not consider load shedding for the N-1-1 contingency of Sunrise and SWPL?

A. The load area targeted for shedding is an urban high population density load area. In addition the lines have a high exposure to outages. Based on information documented in a study performed by SDG&E, over a period of 13 years of fire data, there were 11 fires in the area where the two lines are only four to eight miles apart. One of those fires could have taken out both lines. Although the sample size is statistically small, one could argue that an N-1-1 outage of these lines could occur on the order of once in 13 years[1]. In addition, the WECC Reliability Subcommittee noted the probability of a simultaneous outage trending to one in 21 years, versus 928 years for the originally proposed Sunrise route.

SDG&E, CFE, and IID all have major tie-lines emanating from Imperial Valley Substation. Not only is the reliability of this substation critical for the reliability of the electric supply to each of these utilities, Imperial Valley substation is a seam between these three utilities, and is vulnerable to human coordination errors due to miscommunication and inconsistent practices for taking clearances and designing protection systems. This exposure is a potential contribution towards an increased risk of line outages and the N-1-1 outage in particular. With SONGS retiring, the dependence on Imperial Valley substation increased.

Given the selection of the Sunrise environmentally preferred route, which has a higher outage risk, and the retirement of SONGS, the risk profile impacts of outages interrupting supply from Imperial Valley have significantly increased in recent years. For all of these reasons, load shedding in the San Diego local area is not a reasonable or prudent long-term mitigation solution for the N-1-1 contingency.

Q. How much load shedding would be required under a 1 in 10 peak load condition if the ISO were to plan to a G-1/N-1 only?

A. The load shedding would be accomplished via an existing safety net special protection scheme. The safety net has two blocks of approximately 500 MW of load each. Therefore, if the ISO were to plan for only the G-1/N-1, we would need to shed 500 MW of load for the N-1-1 contingency. However, the incremental

[1] Data from Performance Category Upgrade Request for Imperial Valley - Miguel 500 kV and Imperial Valley - Central 500 kV Double Line Outage Probability Analysis Seven Step Process Document Final Report Prepared By San Diego Gas & Electric Transmission Planning dated December 19, 2007

procurement difference between the G-1, N-1 and the N-1-1 criteria would only be approximately 150 to 300 MW, not 500 MW.

Q. If the Commission adopted load shedding as a long-term, transmission planning mitigation solution for this particular N-1-1 Category C contingency, what would be the impact across the ISO grid?

A. As described above, the exposure to outages of the SWPL and Sunrise lines is higher than average, so if it were deemed that the risk and consequences of this N-1-1 was acceptable, then the risk and consequences of all other category C contingencies and their associated mitigation plans would conceivably be measured against this particular N-1-1. It would also be conceivable that numerous load dropping SPSs across the ISO, which involve large amounts of load drop, would be identified as equally acceptable mitigation plans to be installed in lieu of transmission upgrades and generation procurement.

Q. Doesn't SDG&E have a WECC-certified load-dropping "safety net" in place that is automatically triggered under certain circumstances?

A. Yes. This safety net is currently utilized for the category D simultaneous contingency of both lines. Under normal conditions (e.g. no nearby wildfires, normal wind speeds, no lighting storms, etc), the risk of a simultaneous outage of both lines is significantly lower than an overlapping outage. One additional point is that planning for the N-1-1 increases the available resources that can be called upon to protect against the simultaneous outage when outage exposure is known to be higher (e.g. nearby wildfires, high wind speeds, nearby lighting storms, etc). The safety net may also need to be utilized for the N-1-1 when installed resources are unavailable, depending on the load level.

Q. Is the ISO's approach to planning for the N-1-1 contingency in the San Diego local capacity area inconsistent with the ISO's analysis of the benefits of Sunrise that were recognized in D.08-12-058, as Mr. Powers claims in his testimony on pages 5-7?

A. Mr. Powers correctly points out that it was demonstrated in the Sunrise CPCN proceeding that the Sunrise Powerlink transmission line would add 1,000 MW of reliability to meet the SDG&E LCR under a G-1, N-1 reliability standard, and that upon energization of the Sunrise Powerlink, the SDG&E LCR area would be expanded to include SDG&E's Imperial Valley substation. Both of these points have proven to be true as explained as follows.

The 1000 MW benefit was based on increasing the existing import capability into San Diego from 2500 MW to 3500 MW after an outage of either Sunrise or SWPL. At that time, the ISO assumed that the 3500 MW amount would be based on establishing a 3500 MW WECC path rating to replace the existing 2500 MW WECC Path 44 rating. Also at that time, SDG&E was well into the WECC Path Rating Process for establishing a 1000 MW rating on the Sunrise line itself. Since that time, the 1000 MW Sunrise WECC path rating was found to impair the capability of the internal ISO system line and therefore has been eliminated, as well as any notion of pursuing a 3500 MW WECC N-1 Path Rating, for the same reason. Although these path ratings would have helped ensure that changes within neighboring systems could not impact the capability of the ISO system, and provided reasonable margin for this urban load area which has only two reliable connections (SONGS and Imperial Valley) to the rest of the ISO and WECC, they also would have impaired the capability of the internal ISO system. With Sunrise in-service, the Imperial Valley connection became more reliable, and the path ratings are not being pursued any further. Without the path rating impairing the capability of the internal ISO system, the N-1-1 is the most limiting contingency, and with only the N-1-1 considered, Sunrise provides more than 1000 MW of incremental benefit.

To make this point, I have attached page 3 from my supplemental testimony in A.11-05-023 (Ex. ISO-4). The table on that page shows that the LCR in the San Diego local area need based on the N-1-1 is approximately 2700 MW. The table below compares LCR need based on the G-1/N-1 study methodology utilized by both the ISO and SDG&E in the Sunrise CPCN proceeding, with the LCR need based on the N-1-1 contingency. As can be seen, the San Diego load driving that LCR need was approximately 5700 MW. In the Sunrise proceeding, a 3500 MW import capability after the N-1 was established to determine the LCR need for the G-1/N-1. Using that import capability, with the 600 MW Otay Mesa out of service as the G-1, the LCR need is 2800 MW. Therefore, the LCR need based on the G-1/N-1 utilizing the 3500 MW import capability established in the Sunrise proceeding, with Sunrise completed, is 2800 MW. Utilizing the 2500 MW import capability without Sunrise, the LCR need is 3800 MW. Therefore, the LCR need was actually reduced by 1100 MW with the N-1-1 as the worst contingency. With the G-1/N-1 and the 3500 MW import capability the LCR need was only reduced by 1000 MW due to Sunrise.

		Base Case: Without Sunrise based on G-1/N-1 and 2500 MW N-1 WECC Path 44 Import Limit	**With Sunrise based on G-1/N-1 and 3500 MW N-1 Import Limit**	**With Sunrise based on N-1-1**
1	San Diego Area Load	5700 MW	5700 MW	5700 MW
2	Import Limit	2500 MW	3500 MW	not applicable
3	G-1	600 MW	600 MW	not applicable
4	LCR Need (Line 1 - Line 2 + Line 3)	3800 MW	2800 MW	2700 MW

		Base Case: Without Sunrise based on G-1/N-1 and 2500 MW N-1 WECC Path 44 Import Limit	With Sunrise based on G-1/N-1 and 3500 MW N-1 Import Limit	With Sunrise based on N-1-1
5	Reduction In LCR (relative to the Base Case		1000 MW	1100 MW

I would note that this topic was thoroughly addressed at a workshop held on April 17, 2012 in A.11-05-023.

With respect to Mr. Power's second point about expanding the SDG&E LCR area to include SDG&E's Imperial Valley substation, this has been done. As shown in the 2014 Local Capacity Technical Study report, pages 2 and 94 (Exhibit No. ISO-5), the SDG&E LCR area includes the Imperial Valley substation and the name of the area has been changed to "San Diego/Imperial Valley". However, there are also several LCR Sub-areas within the San Diego/Imperial Valley LCR area including the San Diego LCR subarea.

Q. Both Mr. Powers and Ms. May describe the critical N-1-1 contingency for the San Diego local area as the loss of three major transmission lines- Sunrise, SWPL and the automatic cross-trip of the Otay-Mesa-Tijuana 230 kV line. They then characterize this contingency as an "extreme" event (N-2) and argue that it is incorrect to plan for sufficient generation and transmission to be in place in response to these outages (see, *e.g.* Powers, page 4-5). Mr. Peffer also claims that the N-1-1 contingency is really a Category D event (Peffer, page 7, 11). Is this correct?

A. No. These witnesses appear to be confusing the Category C.3 overlapping outage of SWPL and Sunrise with the extreme contingency N-2 event, which is a simultaneous loss of two transmission circuits. The N-1-1 reference is shorthand for the loss of one element, time for the system to be adjusted (within 30 minutes), followed by the loss of a second element. I note that Ms. May also advanced the argument that because the outage of Sunrise and SWPL results in the planned opening of a third 230 kV circuit and is therefore a Category D contingency, the 2.5% voltage reactive margin should not be applied per language of the WECC requirement (see May testimony at page 34). Because Ms. May has incorrectly classified the contingency, her argument about the 2.5% margin required by WECC similarly has no credibility. Furthermore, as I discussed above, although this WECC requirement is not a mandatory reliability standard, it is a WECC Regional Business Practice that applies to WECC member systems.

Q. How do you respond to Ms. May's testimony that the automatic tripping of the Otay-Mesa-Tijuana line constitutes a third major transmission outage and therefore the N-1-1 is a Category D contingency (testimony, pages 3, 29-31)?

A. The opening of the Otay-Mesa-Tijuana line following the N-1-1 is a planned and controlled opening of the line to protect it and CFE's further downstream 230 kV facilities from overloading following the contingency. The opening of this line is not part of the contingency. A contingency is the unexpected failure of the line, but because the opening of this line is an intentional mitigation measure, it is not a contingency. Alternatively, the ISO could recommend the need for additional generation procurement to avoid the overloading of this line following the contingency, but it is more cost effective to simply plan on the opening of this line. This is also a mitigation that was approved by CFE to protect its 230 kV facilities as a result of a contingency on the SWPL and Sunrise line.

Q. Would transmission improvements prevent the overloading on this line and reduce local capacity needs in the San Diego local area?

A. As explained in my Track 4 Testimony, the ISO is investigating potential transmission mitigation that might address a portion of the local capacity needs.

Q. Ms. Firooz also raises the load shedding issue as well as the probability that the N-1-1 contingency will occur under 1-in-10 peak load conditions. Weren't these issues thoroughly addressed in Track 1?

A. Yes. Mr. Millar, in his Track 1 rebuttal testimony presented a complete description of the deterministic planning standards embedded in the NERC reliability standards and how this methodology compares with a probabilistic evaluation of the transmission system. This portion of Mr. Millar's testimony, as well as a discussion of load shedding and the N-1-1 contingency was submitted in response to the opening testimony of CEJA witness Julia May, who in turn relied on testimony that Ms. Firooz presented in Docket A.11-05-023. In her Track 4 testimony, Ms. Firooz (at pages 5-6) simply has advanced the same arguments that have been considered and rejected by the Commission in two prior proceedings, without providing any new facts or evidence.

Q. In a similar vein, Mr. Powers makes that statement that "The purpose of grid reliability standards is to assure that a utility can continue to provide reliable power during peak demand periods . . . (page 1)." Is this a correct statement?

A. This is incorrect. The purpose is to provide a transmission system that is sufficiently reliable, based on deterministic analysis that considers the periods of most heavily stressed conditions – which at times can be peak loads, off peak, or "shoulder hour" periods where other stressed conditions can emerge. The times of highest system stress for the local areas are in fact currently forecast at peak conditions, but the system needs to be reliable year round, during lower load level periods where the idealized assumption that all other transmission and generation are in-service and operating perfectly is not the case.

Q. Mr. Powers also states that "An example of a Category D event that is directly relevant to Track 4 modeling is the double contingency of SDG&E's Sunrise Powerlink and Southwest Powerlink, an N-1-1 event. . . . (page 2)." Is this a correct statement?

A. No, this is incorrect. The simultaneous (N-2) outage of Sunrise Powerlink and Southwest Powerlink is a Category D event. However, the overlapping (N-1-1) outage of Sunrise Powerlink and Southwest Powerlink is a Category C event.

Q. At page 10 Ms. Firooz points to a FERC notice of proposed rulemaking (NOPR) proposing revisions to TPL-001-4 that would allow load-shedding under certain circumstances for an N-1 contingency. Should the Commission take this into consideration in Track 4?

A. No. The proposed revisions to TPL-001-4 would still prohibit load shedding for an N-1 contingency, but only if certain conditions are met such as providing extensive documentation through a public consultation process, and in no circumstances can the amount of load shedding exceed 75 MW. The purpose of these particular changes in TPL-001-4 is to specify clear limitations on a similar provision that currently exists in existing TPL 001. This NOPR is meant to provide clarity for mandatory enforcement purposes—not to relax the standards and has nothing to do with suggesting, as does Ms. Firooz and other parties, that hundreds of megawatts and thousands of network-connected customers should be dropped for the N-1-1 contingency.

Q. Ms. Firooz also argues, at page 10, that controlled load drop is a more reliable means by which to respond to stressed system conditions than bringing up additional generation, given the complexities of communications and coordination with these resources. What is your response to this testimony?

A. The ISO agrees with Ms. Firooz's statement regarding the complexities of the design and operation of the power system. However, Ms. Firooz ignores the complexity of dropping load. The transmission grid is complex and many things can go wrong that impact reliability. Ms. Firooz does not appear to have taken these complexities into account in her probabilistic analysis which was limited to considering only one contingency condition. In addition to not considering any of the myriad of other contingency and system conditions, (additional generation outages, fires north or south of SONGS, generation and line maintenance outages, etc) Ms. Firooz's analysis did not consider the potential risk associated with an armed load-shedding SPS inadvertently and unnecessarily shedding load when the system is not under stressed conditions. Given the complexities of communications and sensing equipment associated with the load shedding scheme, this is a potential risk, and the magnitude of the risk is proportional to the amount of time that the scheme needs to be armed.

<u>Other Transmission Planning and Study Methodology Issues</u>

Q. In addition to the N-1-1 contingency, load shedding and the WECC-required voltage support margin, parties have taken issue with other aspects of the ISO's LCR study methodology and transmission planning requirements. Are these topics that should be considered in Track 4?

A. No. As I stated previously, the ISO believes that the study methodology- which is the same LCR methodology used for many years in the Commission's resource adequacy proceeding- was adopted in Track 1 and was not an issue to be re-litigated in Track 4. Constantly re-evaluating this decision is not an efficient use of time and resources for the Commission and the parties. However, because there have been other planning and study issues raised in intervener testimony, I will respond to some of these points.

Q. At page 7 of his testimony, Mr. Powers states that the ISO's assumptions regarding the operational capabilities of combined cycle plants, for the purposes of applying the G-1/N-1 contingency standard, is "fatally flawed." What is your response?

A. I disagree. The ISO applies a performance-based standard in this case. As stated in the ISO Planning Standards (Exhibit No. ISO-6), a single module of a combined cycle power plant is considered a single contingency (G-1) and shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002). Furthermore a single transmission circuit outage with one combined cycle module already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002). A re-categorization of any combined cycle facility that falls under this standard to a less stringent requirement is allowed if the operating performance of the combined cycle facility demonstrates a re-categorization is warranted. The ISO will assess re-categorization on a case by case based on the following:

a) Due to high historical outage rates in the first few years of operation no exceptions will be given for the first two years of operation of a new combined cycle module.

b) After two years, an exception can be given upon request if historical data proves that no outage of the combined cycle module was encountered since start-up.

c) After three years, an exception can be given upon request if historical data proves that outage frequency is less than once in three years.

Consistent with this planning standard, the ISO assessed the historical outage rates of Otay Mesa (the limiting contingency in the G-1, N-1 scenario) over the period between 2009 to 2012 and determined that the plant had full plant outage frequencies well beyond once in three years. Otay Mesa has had 14 full plant outages over the three year period. (The ISO will be reviewing the most recent outage history of Palomar, as its performance has been improving in this regard.)

In his testimony, Mr. Powers takes issue with the ISO's use of the entire output of the Otay Mesa combined cycle generation facilities for the purpose of establishing the largest generation unit offline (the G-1). Mr. Powers asserts that the gas turbines have the ability to ride through the loss of the steam turbine, and that the ISO should therefore consider that the plant should be modeled differently. However, based on historical performance over the last three years that I described above, there is no indication that the plant is capable of this performance or, if the plant does have this capability, what new conditions would lead to the gas turbines riding through the loss of the steam turbines now when they have not in the past. Mr. Powers claims there were no economic reasons for the plant to ride through the loss of its steam turbines, but also provides no basis for this claim. Of course, the ISO will reconsider the treatment of this plant if the performance-based standard for demonstrating reliable capability is met in the future.

Q. Ms. Firooz, at page 6 of her testimony, states that the amounts of existing generation used in the ISO's 2012/2013 transmission plan are "conservative" and based on NQCs established by the ISO, rather than nameplate capacity. Is this correct?

A. Ms. Firooz is correct in that the ISO does use the NQCs of generating units in its transmission planning studies. However, NQC calculations based on the production from non-dispatchable generation is not set by the ISO, but rather the Commission, according to well-established resource adequacy procedures. Furthermore, contrary to Ms. Firooz's statement, the NQC for gas fired generation, other than non-dispatchable small QFs, is not affected by forced outages.

Q. At page 11, Ms. Firooz testifies that she conducted a power flow analysis by modifying the ISO's base case and then testing it by taking the worst case scenario for the LA Basin (the outage of the 230 kV Serrano-Lewis #1 line followed by the outage of the Serrano-Village Park #2 line- an N-1-1 contingency). According to Ms. Firooz, this analysis did not result in any reliability violations. Should the Commission use this analysis in making procurement decisions in Track 4?

A. No. This is not the worst contingency driving resource needs in the LA Basin with SONGS retired. Furthermore, even ignoring the N-1-1 contingency, it does not appear that Ms. Firooz conducted a contingency analysis to determine the next worst contingency. Therefore her study is incomplete and should not be relied upon to make procurement decisions.

<u>Track 4 Modeling</u>

Q. At page 14 of her testimony, Ms. May states that while the ISO claims to have followed the May 21, 2013 Revised Scoping Ruling required modeling assumptions, "these assumptions are frequently not actually used to meet needs." She then goes on to address several different modeling assumptions. Is Ms. May correct on these points?

A. No. I have reviewed the ISO's studies and will address each of her points below.

Q. Did the ISO accurately account for the 997 MW of demand response resources that the ISO was instructed to use to reduce the need in the case of an N-1-1 contingency?

A. Yes. Ms. May misunderstands the instructions in the Revised Scoping Ruling. As I explained in my opening testimony at pages 6-7, the Scoping Ruling identified 173 MW of demand response for the LA Basin and 16 MW of demand response for San Diego that was to be used following the first contingency (i.e. post first contingency) to address the first contingency as the system is readjusted in preparation for the next overlapping contingency. The demand response utilized for the post first contingency is a fast response type program located in more effective areas in southern Orange County and San Diego load areas. The additional 997 MW were then to be relied upon following the second contingency (i.e. post second contingency) to address the post second contingency conditions. The post-second contingency demand response is not fast enough to be effective at preparing for the second contingency, but it could be effective at mitigating subsequent contingencies which could happen after a period of time following the second contingency. Once the second contingency has occurred, the next contingency would be considered an extreme event, and although the ISO would need to be prepared for this event, from a planning perspective, it is classified as a Category D event. This language in my opening testimony apparently caused Ms. May some confusion.

Q. At page 15, Ms. May criticizes the ISO's modeling assumptions for customer-side distributed generation, stating that the 796 MW reflected after the second contingency is incorrect and that these resources were only used "to a certain extent," referring to your opening testimony. What is your response to this testimony?

A. Again, Ms. May misunderstands the instructions in the Revised Scoping Ruling. As I explained in my opening testimony (pages 7-8),the customer connected small PV was relied upon following the second contingency (post second contingency). One clarification is that the 796 MW of customer connected PV was the amount determined by the ISO that would potentially avoid activating the safety net after some extreme contingency events, based on technical power system modeling analysis.

Q. Citing to an ISO data request response, Ms. May has concluded that the ISO did not account for the 50 MW of energy storage the Commission directed SCE to procure. Is she correct?

A. No, the ISO did account for the 50 MW energy storage procurement required in Track 1. Apparently Ms. May did not understand the data request response. The data request sought specific information about the energy storage facilities modeled in the study, including nameplate capacity. Because the 50 MW has not yet been procured, the ISO did not have such information for this assumption. Thus, in response to the question, the ISO described only the 40 MW of pumped storage at Lake Hodges and explained that there was no specific information provided about the 50 MW. However, the ISO's understanding is that the 50 MW of storage is included in the 1800 MW of Maximum Track 1 authorization amount, so therefore it is accounted for in the residual resource need calculation in Table 13 of my Track 4 testimony.

Q. Ms. May argues that the ISO should have included the 188 MW of capacity provided by the Cabrillo peakers as existing generation in the San Diego area, citing testimony provided by Mr. Powers in A.11-05-023 (May testimony, pages 19-21). Is this recommendation consistent with the Revised Scoping Ruling?

A. No, the ISO modeled the generation described in the Revised Scoping Ruling, which assumed the retirement of 238 MW of non OTC generation, based on facility age, in the San Diego area which the ISO understands to include the Cabrillo peakers.

Q. Does this conclude your testimony?

A. Yes, it does.